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## Research Article

### Introducing New Slug Size Method in Water Alternating CO<sub>2</sub> for Enhanced Oil Recovery

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**Abstract:** Reduction of hydrocarbon reserves and optimum production is one of major concerns about future of petroleum industry. In the recent years, several enhanced oil recovery methods have been introduced, tested and modified. With increasing methods of improving oil recovery and production techniques, it will be necessary to perform further studies and research to check their feasibility and displacement efficiency. The aim of this research is to study the effect of slug size variation of injection on the displacement efficiency in different scenarios of water alternating CO<sub>2</sub> injection method in a hypothetical reservoir by performing numerical simulations. The results indicate that varying slug size method can yield better performance than fixed water alternating gas ratio, both in terms of recovery factor as well as CO<sub>2</sub> storage. This can open a new look for calculating optimum water alternating gas ratios.

**Keywords:** CO<sub>2</sub> Injection, enhanced oil recovery, reservoir simulation, sequestration, water alternating gas, water slug size

## INTRODUCTION

By increasing oil consumption and depletion of conventional oil reservoirs around the world Enhanced Oil Recovery (EOR) techniques have been developed vastly. The major EOR techniques are thermal flooding, chemical flooding and gas flooding. Thermal flooding, such as steam flooding and cyclic steam stimulation are effective for heavy oil displacement since viscosity of the oil is sensitive to the temperature. Chemical techniques on the other hand, are considered one of the most effective flooding technique in EOR (Thomas *et al.*, 2001). But due to their high consumption of chemical reactants and also safe transportation to the injection well, their usage will be limited (Flaaten *et al.*, 2009; Stoll *et al.*, 2010). Among gas flooding techniques, the most general gas flooding technique is CO<sub>2</sub> flooding. Comparing with air and natural gas, CO<sub>2</sub> has higher solubility in various crudes that makes it more favorable technique. Different mechanisms are associated in CO<sub>2</sub> flooding including viscosity reduction, oil swelling, extraction, gas solution drive and interfacial tension reduction (Beecher and Parkhurst, 1926; Holm and Josendal, 1974; Simon *et al.*, 1978; Miller and Jones, 1981; Mungan, 1981; Klins, 1984; Jha, 1986; Rojas and Farouq Ali, 1988).

The Water Alternating Gas (WAG) process is consisting of injection of gas and water slugs in cyclic form. The main aim of WAG is to improve sweeping efficiency in water flooding as well as gas flooding

while decreasing gas overriding and viscous fingering. Recent studies have shown that WAG technique can be used in secondary and tertiary flooding of reservoirs. Recently, WAG is found to be more effective than gas flooding or water flooding alone. The WAG process increases microscopic displacement by gas flooding and macroscopic sweeping efficiency by water flooding (Christensen *et al.*, 2001).

Factors controlling the efficiency of WAG project include reservoir rock properties, their wettability and heterogeneity. Also, fluids inside the reservoir and injection fluids have great impact on displacement efficiency of the project. The WAG ratio, slug size and injection techniques have to be considered too (Sanchez, 1999).

There are numerous miscible and immiscible WAG processes have been described in different reservoirs (Asghari *et al.*, 2007; Righi and Pascual, 2007; Shi *et al.*, 2008; Chen *et al.*, 2010), yet few attempts have been made to study WAG process under varying slug size condition i.e., different injection duration of CO<sub>2</sub> and water during a project.

In this study we attempt to run high recovery oriented WAG simulations using CO<sub>2</sub> as the gas and see the effect of injection duration on displacement efficiency, leading to prove that the best recovery factor can be made when duration of fluid injection is dependent on real-time CO<sub>2</sub> and water production rates as well as minimum amount of oil production.

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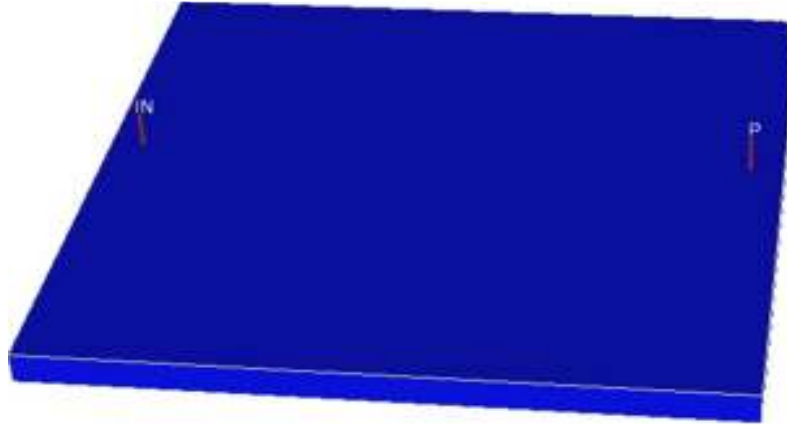


Fig. 1: Reservoir shape and position of the Injection (IN) and Production (P) wells

Table 1: Reservoir data by layers

Layer	Horizontal permeability (mD)	Vertical permeability (mD)	Porosity (%)	Thickness (ft)
1	500	50	30	20
2	50	50	30	30
3	200	25	30	50

Table 2: Reservoir well properties

Name of the well	IN (injection)	P (production)
Location (x, y, z)	25, 1, 1	25, 50, 1
Reference depth (ft)	8400	8400
Wellbore diameter (ft)	0.5	0.5
Minimum bottomhole pressure (psi)	-	1000
Maximum oil/water rate (bbl/d)	12000	12000
Maximum gas rate (MMSCF)	12000	12000

Table 3: Oil sample properties

	Component name	Mole fraction (%)
1	C1	36.47
2	C2	9.67
3	C3	6.95
4	iC4	1.44
5	nC4	3.93
6	iC5	1.44
7	nC5	1.41
8	C6	4.33
9	C7+	34.36

C7+ molecular weight: 218

## RESERVOIR SIMULATION MODEL

The reservoir model used in this study is a in a form of a box, which has heterogeneous geology and the crude oil lies at the depth of 8325 ft. It contains non-uniform geological characteristics (different permeabilities) in form of 3 layers with different permeabilities in x, y and z axis as shown in Table 1.

Reservoir dimensions are 3500×3500×100 ft. The vertical wells drilled in this model are one injection well and one production well, each located on one end of the x axis and middle of y axis of the model as shown in Fig. 1. The perforations are similar since we don't want to allow for gravity effect from injection of CO<sub>2</sub> (in that case production well would be shallower). The properties of the wells are shown in Table 2.

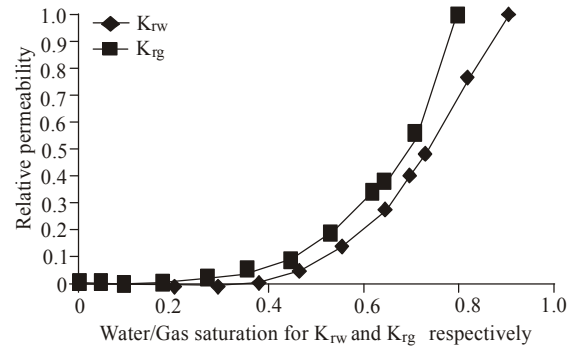


Fig. 2: Relative permeability curves of water and gas based on their saturation

The Gas/Oil Contact (GOC) and Water/Oil Contact (WOC) are situated at depth of 4000 and 9000 ft, respectively. The wells are completed between GOC and WOC.

The initial pressure of the reservoir is 5900 psia and temperature of 160°F. Since it is an isothermal simulation, so CO<sub>2</sub> is above supercritical condition. Also it is assumed that based on the initial data, the flooding is in miscible condition. A live oil sample is generated by PVTi and its mole fraction and component properties are shown in Table 3. PVTi generates all needed PVT data for this simulation. Also, the permeability curves of water and gas are considered as Fig. 2. Figure 3 shows the corresponding oil relative permeability for two regions. First is where only oil and water are present ( $K_{row}$ ) and second is where only oil, gas and connate water are present ( $K_{rog}$ ).

To determine the optimum number of grids used in this study, a base case is considered. The grids are taken in form of 7×7×3 and a parameter such as recovery is calculated. Then by increasing the number of grids (while decreasing each grid size) the before mentioned parameter is calculated until after a specific grid set, no major change is detected. In this case of study, the optimum value of the grids is obtained as 50×50×3. The size of each grid is 70 ft in length, 70 ft in width and for

Table 4: Varying slug size scenario

Step No.	Injection status	Duration with significant production (days from start)	Recovery of the injection section	Total recovery on stoppage point	Total recovery after 15000 days
1	Natural depletion	2410	23.72	23.72	26.30
2	Water#0 (secondary)	5760	35.75	59.47	59.95
3	CO <sub>2</sub> #1	8545	5.77	65.24	70.22
4	Water #1	10190	6.54	71.78	72.61
5	CO <sub>2</sub> #2	10890	0.52	72.30	74.02
6	Water #2	11640	1.55	73.85	74.73
7	CO <sub>2</sub> /water	100/100 from 11640 until the end			77.60

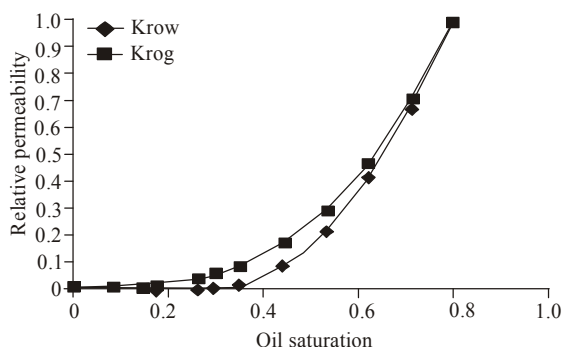


Fig. 3: Oil relative permeability curves versus oil saturation

depth is 20, 30 and 50 ft, respectively from top to bottom.

Different scenarios have been put into consideration for this study subject that as shown in Table 4 and 5. The maximum duration of production is 15000 days. The first scenario is a natural depletion of the reservoir until no significant oil production is detected. Then several scenarios of water injection are considered as secondary recovery, each one with a specific duration of injection.

### SIMULATION RESULTS AND DISCUSSION

The main goal of this simulation is to study the effect of slug size of injection on the displacement efficiency in different scenarios.

In WAG scenarios, it is common that they take a constant ratio of water/gas injection. But in this study, we also check every slug size based of recovery of each step.

The first step is to run the simulator for obtaining primary recovery. After the recovery is almost stopped, then the secondary recovery is simulated using water. After reaching a point where no major production is detected, the tertiary recovery begins with the other phase that is CO<sub>2</sub>.

Different scenarios are used either fixed or varying duration of water and CO<sub>2</sub> injection. In varying slug injection, we use next phase injections start point as the points where recovery by previous phase is not economical. These stoppage points happen when oil production falls below 500 bbl/day or production exceeds 11000 bbl/day or mole percentage of CO<sub>2</sub> in production well exceeds 90%. Then the results are

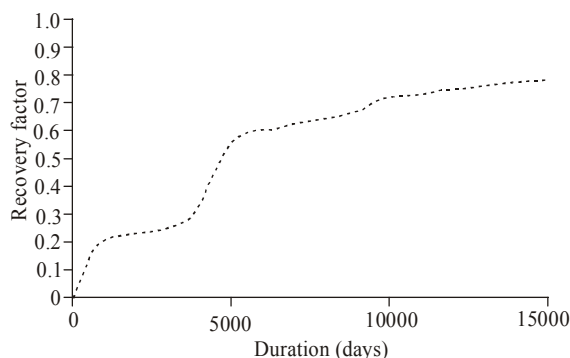


Fig. 4: Recovery factor during variable slug size injection

determined based on duration and amount of injection and different scenarios are compared.

**Results and discussion:** The simulation is started with primary recovery. For this matter we leave the injection well in shut mode in order to let the pressure of reservoir be the only agent forcing the crudes to be produced. After 2410 days of production the recovery factor is almost became steady on 23.72%.

Then, simulation continues for secondary recovery. Water injection is used as secondary recovery agent worldwide. In this scenario we start by water flooding after primary recovery of 2410 days. After 5760 days since the start of production, the production rate dropped rapidly and the water cut increased exponentially. In this point the recovery is recorded 59.47%.

In this step, varying scenario is examined. The CO<sub>2</sub> injection and water injection are performed using before mentioned stoppage conditions. The simulation results are summarized in Table 4.

As shown, after 6 steps, no major recovery is detected and since the stoppage points are determined manually, it is better to switch to a fixed slug size. Therefore, a 7<sup>th</sup> step is considered that is a fixed duration injection of 100 days in each phase after 11640 days from start. An overall recovery trend can be observed as Fig. 4.

Then the results have to be compared with fixed slug size injection. Different injection ratio of 50/100, 100/100, 150/100, 200/100, 100/50 and 100/150 for CO<sub>2</sub>/water injection days are examined after the

Table 5: Fixed slug size scenarios

Scenario No.	Slug size ratios (CO <sub>2</sub> /water injection days)	Total recovery (%)
1	50/100	74.12
2	100/100	77.17
3	150/100	77.38
4	200/100	76.35
5	100/50	76.54
6	100/150	75.10

Table 6: Comparing different factors between varying method and fixed method

Parameter	Varying method	Fixed method
Total water injection (STB)	88,900,000	95,400,000
Total water production (STB)	55,600,000	61,700,000
Total water in place (STB)	46,500,000	47,000,000
Total CO <sub>2</sub> injection (MSCF)	62,200,000	55,700,000
Total CO <sub>2</sub> production (LB-M)	103,000,000	99,200,000
Total CO <sub>2</sub> stored (LB-M)	60,600,000	47,500,000

secondary recovery at 5760 days, respectively. The recovery factors are recorded as Table 5.

Comparing the results from different scenarios show that varying slug size injection based on economic factors can increase the recovery factor slightly. Also, other factors can be compared between the varying slug size method and best fixed method (scenario 3) as shown in Table 6.

The values in Table 6 show that in fixed method, the injection, production and also storage of water is more than varying method. This can be put in an advantage of using variable method. On the other hand, CO<sub>2</sub> injection in variable method is higher and the production is a little higher than of fixed method. But the remaining CO<sub>2</sub> is stored inside the reservoir. Therefore again, the variable method has an advantage in CO<sub>2</sub> consumption too. One more reason to use varying method is the much less need to change the injection modes from one phase to another.

## CONCLUSION

Several simulations are done in a hypothetical reservoir and crude oil sample in order to study the effect of slug size on the recovery factor.

Using varying slug size based on oil production and maximum water/CO<sub>2</sub> production rate, will increase the recovery factor slightly in compare with a fixed WAG ratio.

Although CO<sub>2</sub> consumption was higher in varying method, more CO<sub>2</sub> remained in the reservoir that suggest higher possibility of CO<sub>2</sub> storage when using varying method which usually has a longer injection period for each phase. Also, by using varying method, less amount of water is needed for injection and also less water production is expected while lower water will remain in the reservoir.

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